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State Energy Planning
Roadmap for Policy Makers

Options for Addressing
Emerging Energy Issues in the West

Prepared by the Western Interstate Energy Board
for the Idaho Governor's Office of Energy and Mineral Resources

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Introduction

The State Energy Planning Roadmap for Policy Makers (Roadmap) addresses emerging issues facing the Western electric power system. The Roadmap summarizes significant challenges, highlights key findings, and provides options that policy makers can consider in addressing these issues. The Western electric power system is currently in the midst of the biggest change to confront the system in at least 30 years. This transformation is driven by changes in supply and demand side technologies, federal environmental policies, and state renewable, efficiency and greenhouse gas policies. For example:

- Due to the changes in the Western economy, improvements in energy efficiency technologies and enhancements in state, federal and utility policies and programs, growth in the demand for electricity has been decoupled from growth in the economy. The growth in demand for electricity in the West dropped during the Great Recession and has remained virtually flat over the past five years.

- Due in part to the declining cost of wind technology, wind generation capacity has grown 10,481 MW from 2010 to 2015.

- As solar prices have radically declined, solar generation capacity has grown 10,452 MW from 2010 to 2015.

- Due to historically low natural gas prices, gas fired generation capacity has grown 12,085 MW from 2010 to 2015.

- Since 2010, over 4,000 MWs of coal plant capacity has been retired within the Western Interconnection. More retirements are likely as a result of federal and state policies.

According to the Western Electricity Coordinating Council's (WECC's) 2026 Common Case, these trends within the Western Interconnection are expected to continue. The 2026 Common Case is a consensus stakeholder expectation of the resource mix of the Western power system ten years in the future. Using the best available public information, the Common Case compiles data on both existing generation and the generation needed to meet state Renewable Portfolio Standards and future demands for electricity. Based on the 2026 Common Case:

- Wind generation capacity is expected to reach 29,595 MW by 2026, comprising 7.5% of the energy mix.

- Solar generation capacity is expected to reach 18,408 MW by 2026, comprising 4.2% of the energy mix.

- Gas fired generation capacity is expected to reach 98,611 MW by 2026, comprising 30.5% of the energy mix.

- Expected future cumulative coal plant retirements will exceed 11,000 MWs of capacity by 2026. Coal fired generation capacity is expected to be 30,741 MW, comprising 19.7% of the energy mix.

This Roadmap summarizes work accomplished through a two year, multi-state, collaborative project funded by the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, to foster regional and state energy planning in the West; identify opportunities for multi-state or region-wide collaborations to address emerging energy issues; and develop a roadmap identifying options for policy makers to address selected challenges presented by emerging issues within the Western Interconnection.[1]

The Roadmap addresses four emerging issues facing the Western electric power system, including: a Clean Energy Future and Managing Carbon Risks; Maintaining Reliability with the Integration of Distributed Energy Resources; Integration of Variable Energy Resources; and Coal Unit Retirements and Reliability. Each section of the Roadmap takes an in-depth look at a specific challenge within each issue. These issues were identified through a stakeholder process informed, in part, by regional modeling and analysis. The state of Idaho led the project effort with input from the original collaborating states: California, Colorado, Montana, Nevada, Oregon, Washington and Utah. Additional input for the project was provided by the Western Interconnection Regional Advisory Body (WIRAB), the Committee on Regional Electric Power Cooperation (CREPC), the Western States Air Resources Council (WESTAR) and the province of British Columbia. All Western states were invited to, and did, participate in the project. Each challenge section included below is explored in greater detail in corresponding technical briefs.

[1] The project summary is available at: http://westernenergyboard.org/wp-content/uploads/2015/06/05-22-15-wiebbd-bkgrd-FOA-Description-final.pdf.

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Clean Energy Future and Managing Carbon Risk

Section 1. Coordination of Energy Efficiency (EE) Evaluation, Measurement and Verification (EM&V) Among Western States

Background

Energy efficiency (EE) is a recognized and growing part of the resource mix on the Western electricity grid. EE is the use of less energy to perform the same function or provide the same or an improved level of service to the energy consumer. Specifically, demand-side EE means reducing energy consumption at the point of use, typically at consumers' facilities — such as a factory, home or office building — and also non-facility uses such as street lighting or agricultural pumping. EE can be a low, and perhaps the lowest, cost option for reducing air emissions at power plants.

Demand-side EE has a wide variety of benefits: it lowers a utility's cost of electricity and reduces generation, transmission and distribution infrastructure costs; helps stabilize electricity market prices; improves system reliability and energy security; and provides a wide range of non-energy benefits to consumers and society as a whole, such as reduced air pollution. This is due in part to Western state and federal policies and regulations, such as state EE goals and air pollution reduction regulations. Notably, the U.S. EPA's Clean Power Plan (CPP) endorses EE as a tool for compliance and includes incentives to promote EE.

Evaluation, measurement and verification (EM&V) involves assessments aimed at determining the effects of EE actions. EM&V is a valuable component of any EE program, and is typically required because it documents results and provides a basis for assessing and improving program performance. EM&V can be highly technical and, depending on established protocols, can be expensive to develop and implement.

This section summarizes the findings of the technical brief titled *Coordination of Energy Efficiency (EE) Evaluation, Measurement and Verification (EM&V) among Western States*.

Key Findings

EM&V is a mature industry with a rich amount of collected data and information. However, the development of industry guidance and protocols for documenting efficiency savings has been primarily driven by state Public Utility Commission (PUC) requirements for EE programs funded by utility customers. Efforts to coordinate EM&V and develop forums for shared information resources have significant gaps.

Broader coordination can increase the quality and reduce the cost of EM&V. Multi-state or regional coordination of EM&V can:

- Facilitate and improve the quality of EM&V;

- Facilitate interstate (and intrastate) benchmarking, disclosure, and tracking of EE projects and associated electricity savings by improving the consistency and quality of EM&V procedures;
- Support trading of EE savings credits, if used for pollution reduction programs or regulations; and
- Reduce EM&V development and implementation costs.

Coordinating EM&V efforts can present challenges. Generally, these challenges include the potential for some loss of state control, the implementation of "lowest common denominator" products or services that do not meet the needs of some participating states, and increased costs and delays through coordination inefficiencies or failures. While these potential challenges can be mitigated, they do require attention to issues such as decision-making structure. Strategies requiring higher levels of coordination and agreement can be more challenging to implement.

New applications for EE EM&V continue to emerge. Demand response (DR) resources and electric vehicle (EV) charging present new applications for EM&V. DR can contribute flexible capacity needed to maintain real-time balance and reliability of the electric power system. The California Independent System Operator (CAISO) is currently exploring the appropriate EM&V process to assess DR. The ability to flexibly manage EV charging can provide a new kind of distributed resource at the distribution level. Several Western states are currently exploring methods for measuring and evaluating this resource.

Options for Moving Forward

Given the benefits and opportunities associated with coordinating EM&V, policy makers could consider the following options:

Option 1: Establish an EM&V information clearinghouse.

Policy makers may want to consider developing an information clearinghouse to promote EM&V coordination. As a tool for building EM&V coordination, the information clearinghouse requires low level of coordination and, therefore, is at little risk of being impeded by issues that can challenge other options. The clearinghouse, in addition to being a valuable stand-alone tool, could also serve as a springboard from which interested participants could develop EM&V products or engage in higher levels of coordination on EM&V topics. In developing an information clearinghouse, states can:

> **Explore funding opportunities.** A national laboratory, such as the Lawrence Berkeley National Laboratory (LBNL), could discuss with the U.S. Department of Energy the potential for funding to cover at least the initial set up and technical support of a more substantial clearinghouse.
>
> **Establish an EM&V discussion forum.** A regional entity, such as the Western Interstate Energy Board (WIEB), could establish a forum for information dissemination and

discussion on EM&V. This could be as minimal as planning and organizing one or more webinar series to address issues like best practices or newly arising applications for EM&V such as DR and EV charging.

Establish a stakeholder advisory group. States can establish a stakeholder advisory group that could provide feedback on the parameters of a clearinghouse, for example, the format and information that could be shared. States could ask a regional entity, such as WIEB, to provide a convening and facilitation role. A regional organization partnering with technical experts, such as staff at LBNL, could provide assistance establishing and staffing a stakeholder advisory group to provide feedback on key aspects of the clearinghouse as it develops and ongoing guidance and feedback after it is established. A regional entity that has partnerships and experience with state policy makers and other key stakeholders could leverage their connections and experience to reduce some of the work load and expense associated with developing and operating an EM&V information clearinghouse.

Possible formats for an EM&V information clearinghouse may include: a web site; webinars, workshops or conferences; and/or information sharing or technical assistance networks. Information that could be shared includes: EM&V methodologies, deemed savings values, state framework documents and protocols, technical papers, links to regulatory filings and orders, professional contact information, and case studies and lessons learned.

Option 2: Develop EM&V resources, products and tools.

Participants can engage in the mutual (voluntary) development of specific EM&V products that support consistent, cost effective EM&V implementation, such as standard EM&V reporting formats/templates, a regional database of consistent deemed electricity savings values, a regional glossary of definitions and concepts, regional standardized efficiency EM&V methodologies, or regional EM&V professional standards or accreditation processes.

Option 3: Develop a regional EE registry and tracking system.

The primary function of this entity would be an EE tracking system, but it could also include roles in trading and compliance reporting. This strategy involves development and implementation of an entity that administers—for individual states and across the region—EM&V procedures, rules and reporting infrastructure for EE programs and projects. One possible option could involve expansion of the Western Renewable Energy Generation Information System (WREGIS).

A more detailed discussion of these options is located in the technical paper associated with this summary.

Section 2. Linking Programs to Achieve the Potential Benefits of Larger Carbon Markets

Background

Carbon pricing is a strategy being utilized by some Western states to achieve clean energy policy goals. Other states are exploring this strategy due to state specific priorities or as a response to potential federal regulation. Carbon pricing is a cost that is applied to carbon emissions to encourage emitters to reduce the amount of greenhouse gas (GHG) they emit into the atmosphere. This has been done primarily through cap and trade programs or applying a tax directly on emissions. When employing this strategy, there are potentially significant benefits from participation in larger markets. Given that different carbon emission reduction policies and programs are developing in the West on a state-by-state basis, Western states may be interested in how to link with other programs to gain the benefits of a larger carbon market. Other benefits are associated with linking as well.

Linking can mean full two-way participation in an existing carbon trading system, such as the Regional Greenhouse Gas Initiative (RGGI) or the Western Climate Initiative (WCI). This includes mutual acceptance of allowances for compliance between state and provincial cap-and-trade programs and sharing administrative services such as an auction platform and allowance tracking system. Linking may also be something more limited, such as only recognizing allowances from another system for compliance in a state's program.

This section summarizes the findings of three technical briefs written under the umbrella of *Linking to Achieve the Potential Benefits of Larger Carbon Markets*, including: (1) *Considerations for Western States*; (2) *Requirements of the Greenhouse Gas Initiative (RGGI)*; and (3) *Requirements of the Western Climate Initiative (WCI)*.

Key Findings

There are substantial differences in the West regarding each state's capacity to develop and implement a carbon reduction program. For example, states have different levels of expertise and experience with cap-and-trade programs and may have variable staff and financial resources available to support a carbon reduction program. Some smaller states (as measured by population and revenues) may be interested in exploring cap-and-trade as a potential tool to meet state and federal policies, but resource limitations could present a barrier to exploring and potentially developing such programs.

Linking increases price stability and reduces administrative costs. Linking functionally expands each jurisdiction's program into a single larger program. This increases compliance flexibility and allowance market liquidity and, therefore has the potential to lower the overall cost of compliance, increase price stability and promote reliability. Linking promotes reliability by maintaining generation resource options across a larger regional footprint. A key reason for linking is the increase in cost effectiveness that can result from wider access to low-cost emissions reductions. Linking can reduce administrative costs for states with limited staff and resources by providing needed support services, allowing cost sharing for administrative systems and technical resources, and avoiding duplication of effort. Linking can also reduce administrative costs for regulated entities by creating a more consistent set of rules and procedures across the region and can alleviate competitive concerns caused by leakage. To the extent that linkage reduces carbon price differentials across states or regions, it reduces the potential for leakage --the movement of economic activity to jurisdictions that do not regulate emissions in the same way. *See Considerations for Western States*.

Linking can present challenges. Linking can result in some loss of jurisdictional autonomy, the potential for some loss of co-benefits and distributional impacts. Many of these challenges can be managed through choices in program design. The first step to address a state's concern about the potential for some loss of autonomy is to understand what is required to link with a particular program or jurisdiction. Modeling can provide valuable directional insight in regard to the outcomes of program design choices. *See Considerations for Western States*; *R*equir*ements of RGGI* and *The Requirements of WCI*.

To fully link with RGGI, cap and trade programs must be consistent with the RGGI Model Rule. The Model Rule is a model set of regulations that detail the requirements for a proposed program. It serves as guidance and is revised periodically to reflect program changes agreed to by RGGI states. The cap and trade programs of RGGI states cover $C0_2$ emissions from fossil fuel fired electric generating units (EGUs) with a rated capacity of at least 25 megawatts in participating states; imports are not covered. State emission reduction targets reflect a regional goal of 60% below average 2000-2002 levels by 2020.[2]

To fully link in the Western Climate Initiative, programs must be "harmonized" with other linked programs. A jurisdiction must adopt cap and trade regulations that are "harmonized" with the regulations of the other linked jurisdictions. There is no model rule, primer or summary of the regulations from the linked jurisdictions.[3] A new entrant works with those jurisdictions in designing or amending its program regulations. In general, the overall standard is to provide the same level of stringency and environmental integrity while providing equivalent coverage of emissions in all jurisdictions. The California, Quebec and Ontario programs all have GHG emission targets at least as stringent as 1990 levels by 2020, and cover the following: multiple GHGs including carbon dioxide, sources that emit 25,000 metric tons or more of CO2e (CO_2 equivalent) annually, and multiple sectors including electricity and electricity imports. *See Requirements of WCI*.

Linking is not an all or nothing proposition. There are different types and degrees of linking and states could take some steps toward linking now and reserve other decisions for later.

Both systems (RGGI and WCI) allow limited unilateral participation in that there is no restriction on who can buy allowances in their auctions, however, program changes are currently being explored that could impact interactions with states (or entities in states) that are not full participants in RGGI or fully linked with the other WCI jurisdictions. California Air Resource Board (CARB)

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[2] In 2014, the regional emission reduction target was set at 45% below the average of 2000-2002 emissions, it decreases annually by 2.5% from 2015-2020. State annual allowance budgets are set so that these targets will be met. *See Requirements of RGGI*.

[3] There are a series of design recommendation documents that were released 2008-2010 that continue to serve as "guide posts." However, these documents do not get updated and are not held out as the standard by which jurisdictions evaluate their regulations. *See Requirements of WCI*.

staff has submitted to the Board proposals to amend their regulations to include two specific forms of unilateral linkage. RGGI is currently undergoing a comprehensive program review and one question they are specifically considering is: Should the RGGI states consider allowing trading with states that do not become participants in the RGGI program? *See Requirements of WCI*; and *Requirements of RGGI*.

The ROs, RGGI and WCI, Inc., offer different services to participants. RGGI, Inc. provides policy support to participating jurisdictions and WCI, Inc. does not. Both ROs offer technical services (provided largely through 3rd party contracts that the ROs manage) such as an auction platform and allowance tracking system. Neither has regulatory or enforcement authority; that remains with the states and provinces. However, RGGI, Inc. provides support for state program development and implementation and a forum for deliberation for the participating states. WCI, Inc. does not provide any policy support and services are limited to operational support such as design and implementation of the auction and allowance tracking systems and on-board preparation by jurisdictions that will be using their services.

Options for Moving Forward

Given current trends in state and federal policies, states may want to manage the risk of carbon regulation by doing their due diligence which includes understanding the range of options available and the implications of choosing one tool over another. States considering cap and trade as a tool for reducing carbon emissions may also want to consider the potential benefits that could be obtained by participating in a larger carbon market. In order to do this, policy makers could consider the following:

Option 1: Investigate options for participating in an existing carbon market.

States considering carbon regulation policies could investigate options for participating in an existing carbon market such as RGGI or WCI. A key issue to address would be whether compliance with emission reduction policies and regulations is more economical, efficient, and/or cost effective by participating in an existing market or by going it alone.

States could also request that WIEB or another regional organization, organize, explore potential funding resources, and oversee a regional study that would provide insight into state and region-wide impacts of various policy choices and regulations. This could include establishing a stakeholder advisory group to provide guidance throughout the process. Study parameters could include, for example: analyzing where the region and states composing the region are in relation to meeting state or federal regulatory requirements under business as usual assumptions; and/or analyzing the economic, environmental (e.g. location of emission reductions) or electric system reliability impacts of different combinations of emission reduction tools in the Western states and provinces.

Option 2: Develop a forum for discussion and the exchange of expert information.

With consequential policies and regulations currently in various stages of development and implementation, states may benefit from a forum that tracks and monitors key developments while providing opportunities for the exchange of expert information and the occasion for deliberation by Western policy makers and other stakeholders.

To implement this option, States could request that WIEB, or another regional entity, develop a forum for the exchange of information between state policy makers and other experts on topics that are most relevant to Western state policy makers and regulators. As an example, the forum could include a webinar series on key issues regarding participation in RGGI or WCI that would bring together professionals from those initiatives, experts from other organizations, and Western state policymakers, regulators and other stakeholders.

Option 3: Reduce barriers and increase incentives to participation in the WCI.

To implement this option, linked jurisdictions using the WCI, Inc. auction and administrative services could develop a product summarizing the regulations that a new entrant would need to "harmonize" with in order to link. Currently the linked jurisdictions are California, Quebec, and in 2017, Ontario. A new entrant must harmonize its cap and trade regulations with the regulations of all three jurisdictions in order to link. This product could take the form of a primer, a model rule, or a summary of the relevant regulations for each jurisdiction, and the product could be updated to reflect changes in state or jurisdictional regulations.

The WCI, Inc. Board could consider expanding support services to include more state program support. For states in which resource limitations are a barrier to considering cap and trade as a tool for addressing emission reduction policies, outsourcing some of the work required for designing, implementing and operating a state cap and trade program is a potential solution. WCI, Inc. is uniquely positioned to provide some of these resources, similar to the resources RGGI, Inc. provides to states. However, it is currently limited by its bylaws to providing operational (or on-board) services to states.

Option 4: Develop a mechanism for engaging with RGGI and maximizing the influence of Western states.

This is an opportune time to engage with RGGI and influence program development as a comprehensive program review is currently underway. RGGI has not had a new state participant since trading began in 2008 and its current members are all from the same geographic region (New England and the Mid-Atlantic). Interested Western states could come together to: become familiar with the changes being considered in the RGGI program review, such as participation for nonmembers and potential compliance with the U.S. EPA's Clean Power Plan; explore the most effective avenues for providing feedback or comments; discuss the interests and perspectives of the different Western states; and possibly develop shared positions. A regional entity, such as WIEB, could assist in establishing and staffing a Western States working group. Staff work could include, for example, providing meeting forums, developing agendas, arranging experts to provide information, monitoring the RGGI program review and researching issues as needed.

Maintaining Reliability with the Integration of Distributed Energy Resources

Section 3. Distributed Energy Resource Interconnection Timelines and Advanced Inverter Deployment: Their Improvement in the Western Interconnection

Background

The nameplate capacity of distributed energy resources (DERs) is increasing within the Western Interconnection. DERs include generation and other power sources that are not centrally-located. While residential solar photovoltaic (PV) power generation is the prototypical DER, several other types of DERs exist, including other generation technologies (e.g., combined heat and power), load management (also known as demand response), and storage, which can assume a variety of forms (e.g., hybrid solar PV generation/storage systems, electric vehicles).

In order for the energy of DERs to be grid-available, they must be interconnected with the electric grid. Processes for interconnection are in evolution as utilities and regulators improve their understanding of interconnection requirements and of potential streamlining of these processes. In addition to interconnection processes, reliability must be ensured with grid-interconnected DER.

This section summarizes the findings of the technical brief titled *Distributed Energy Resource Interconnection Timelines and Advanced Inverter Deployment: Their Improvement in the Western Interconnection*.

Key Findings

There are four stages to establishing interconnection with the electric grid. Using a distributed solar PV generating system as a DER example, these stages include:

1. Interconnection application review and approval –utility review of application completeness to interconnection approval by the utility

2. Construction –installation of the solar PV system

3. Building inspection by local permitting jurisdiction –local jurisdiction's completion and submission of verification of a passed building inspection (i.e., compliance with building and fire codes) to utility

4. Permission to operate – permission provided by the utility to the solar PV installer

Utilities process thousands of interconnection applications each month. A 2015 interconnection study by the National Renewable Energy Laboratory (NREL) included more than 30,000 residential systems. This study was timely because several utilities in the Southwest, including Arizona Public Service, Pacific Gas and Electric, and San Diego Gas and Electric, process 1000 or more interconnection applications per month.

Establishing an interconnection is a lengthy process. The 2015 study by NREL assessed the median duration of each of the four interconnection establishment stages for both residential and commercial solar PV systems during years 2012-2014; we will focus here on residential systems. Interconnection application review and approval for residential systems required a median duration of 18 business days to complete. Construction, on the other hand, required a median time of just 2 business days. Building inspection had a median duration of 4 business days, and the permission to operate stage had a median time of 10 business days. The entire interconnection process for residential solar PV systems had a median duration of 52 business days. Commercial systems required slightly longer times for all stages. It is likely that variation in requirements and processes across utilities and local permitting jurisdictions contribute to these relatively lengthy timelines.

Streamlining the application and approval stage can significantly expedite the interconnection process. In addition to the above-mentioned, national-level study NREL, in 2015, published a case study of the California investor-owned utility Pacific Gas and Electric (PG&E). This utility was selected for study because it had interconnected more than 130,000 solar PV systems within its distribution systems by the end of year 2014, ranking it first among U.S. utilities. After eliminating unnecessary application requirements (e.g., detailed insurance review), PG&E focused on streamlining and automating the interconnection application stage. PG&E's online application process is associated with several benefits (e.g., allows the processing of an application to be tracked). These improvements have resulted in typical interconnection application stage duration of 3 days in spite of an increase in applications received from approximately 1000 to 5000 per month over years 2012-2014. This time compares very favorably with the above-mentioned, national-level duration of 18 days.

Advanced smart inverter functions, as technical operating standards, can enhance grid reliability. Two organizations are prominent in developing national standards for interconnection of DER, the Institute of Electrical and Electronics Engineers (IEEE) and Underwriters Laboratories (UL). National standards are important because they are often referenced by state-level entities; for example, the California Public Utility Commission's (CPUC) Revisions to Electric Tariff Rule 21 references IEEE Standard 1547, as well as UL Standard 1741.

CPUC Electric Tariff Rule 21 generally concerns interconnection of distributed power generation with distribution systems. Rule 21 has been revised twice in recent years. The first revision, which occurred in late 2012, concerned studies of impacts of DER interconnection on distribution systems. A CPUC decision that adopted additional revisions to Rule 21 was issued in late 2014. This decision included an adoption date of the approval date of the above-mentioned UL Standard 1741 (Supplement A, specifically; approved in September, 2016). The 2014 revisions to CPUC Rule 21 were recommendations of the Smart Inverter Working Group (SIWG). Advanced inverters, also known as smart inverters, are typically controlled by sophisticated microprocessors or digital signal processors which allow them to provide a number of advanced functions that can be utilized to enhance grid reliability. CPUC Rule 21 (2014 revision) incorporates several of these capabilities as technical operating standards. These capabilities include anti-islanding protection, low/high voltage and low/high frequency ride-through capabilities, dynamic volt/var operations, ramp rate control, adjustable fixed power factor, and re-connection by so-called soft-start methods.

Options for Moving Forward

The following policy options are offered for Western states and provinces:

Option 1: Strive for consistency in requirements and processes for DER interconnection across authorities having jurisdiction.

Consistency is especially important for reducing the time and cost of interconnection and building permitting processes among utilities and local permitting jurisdictions, respectively. Consistency will also benefit the solar PV sector that operates in multiple jurisdictions.

Option 2: Adopt revised IEEE 1547, which includes the advanced inverter capabilities introduced in the SIWG's Recommendations to the CPUC.

Importantly, adoption of revised IEEE 1547 will enable the use of advanced inverter capabilities and will enhance reliability in the Western Interconnection.

Option 3: Ensure remote inverter programming capability for inverters, permitted by communication of DERs, facility systems, and aggregators with a utility.

Such communication will permit remote enabling and updating of advanced inverter capabilities, and will allow more coordinated management of DERs within distribution systems. Remote enabling, in turn, requires interconnection agreements that allow utilities to change operational characteristics of inverters when necessary. IEEE 2030.5 (last version, 2013; currently being revised by the Smart Energy Profile 2.0 working group) is the most likely standard to be adopted in order to enable remote programming capability.

Section 4. Distributed Energy Resources: Technological and Policy Considerations of Hosting Capacity and Locational Value

Background

The nameplate capacity of distributed energy resources (DERs) is increasing within the Western Interconnection. The Western Electricity Coordinating Council's (WECC's) 2026 Common Case indicates that Western Interconnection-wide DER nameplate capacity will increase to more than 16,000 MW by 2026. This projection is more than twice that made just two years ago for year 2024. DERs include several generation technologies (e.g., rooftop solar photovoltaic (PV) generation, combined heat and power), load management (e.g., demand response, energy efficiency), and various forms of storage (e.g., hybrid solar PV generation/storage systems, electric vehicles). While DERs provide several benefits, they also pose several challenges to the electric power system. Benefits and costs of DERs can be grouped into three principal categories: infrastructure-related, energy-related, and environment-related.

Importantly, many benefits of DERs are not uniform, but instead vary according to time and location. The locational influence can lead to avoidance of infrastructure costs because lesser investments in centralized generation, transmission and/or distribution may be needed with DERs. The use of DERs can result in avoided infrastructure costs which may amount to millions of dollars, as recent examples from utilities in California and New York demonstrate.

This section summarizes the findings of the technical brief titled *Distributed Energy Resources: Technological and Policy Considerations of Hosting Capacity and Locational Value*.

Key Findings

Hosting capacity refers to the DER nameplate capacity that can be interconnected with a portion of a distribution system. Importantly, this definition assumes that upgrading of system infrastructure is not required for interconnection of this nameplate capacity; however, system infrastructure upgrades are typically needed to increases hosting capacity to avoid negative impacts on power quality or reliability. A DER must be interconnected with a distribution system in order to make its power output available to the electric grid. In approving interconnection of a DER, a utility must ensure that the DER does not negatively impact electric power quality or reliability.

Implementation of a fast track screen can expedite interconnection approval for DERs. Expedited interconnection approval can usually occur if a so-called fast track screen is passed. A fast track screen serves as a proxy for more technical assessment of an interconnection request if the DER is unlikely to have negative impacts on electric power quality or reliability. Interconnection of low-impact electric power generation, such as distributed solar PV in an area with a low level of DER penetration, is usually expedited. Low penetration has frequently been defined as a distribution feeder or feeder line section with a total DER capacity of less than 15% of annual peak load. Common practice for distribution planning engineers is that most distribution system feeders in the U.S. have minimum daily loads of approximately 30% of their annual peak loads; thus, the 15% screen is relatively conservative. The 15% screen also fails to take into account the heterogeneity of feeders comprising distribution systems. This heterogeneity includes feeder topology, design and operation, as well as geographic location of a feeder.

DER location is arguably the most significant factor in determining hosting capacity. Hosting capacity of a distribution feeder or feeder line segment is determined by a number of factors, including DER location on the feeder, feeder topology, design and operation, DER technology, and geographic location of a feeder. Of the identified factors, DER location is arguably of greatest importance in determining hosting capacity. These determining factors can lead to DER hosting capacities that vary considerably both within a given feeder and among feeders. Adding to this complexity, distribution system infrastructure upgrading costs vary widely among feeders. DERs are most beneficial in locations where DERs can serve as a lower-cost alternative to traditional distribution infrastructure upgrading.

States are beginning to consider the locational value of DERs. DERs have only recently made significant contributions to the grid, so little consideration has typically been given to where they are located in distribution systems. Lack of consideration of the above-mentioned heterogeneity in hosting capacity and distribution system infrastructure upgrading costs, however, appears to be ending in certain states. California, a state that has experienced accelerating annual solar PV deployment, has ongoing proceedings in which locational value of DERs and their infrastructure cost avoidance are being considered. New York, a state with lower DER growth than California, is more proactively considering DER value with respect to both hosting capacity and infrastructure cost avoidance.

The California Public Utilities Commission (CPUC) and the New York Public Service Commission (NYPSC) are now requiring, or will soon require, distribution system plans. The CPUC required submission of such plans for the first time in 2015; the NYPSC will require distribution system plans in the near future. These plans are expected to identify beneficial locations for DER deployment by specifying where DERs can be substituted for traditional infrastructure upgrading. The importance of DER locational value is highlighted by these requirements of regulatory agencies in California and New York.

Options for Moving Forward

Hosting capacity and its use in DER interconnection screening, due to its maturity, is more straightforward for which to provide policy options. Valuation of DER location is in its infancy, and is therefore more challenging for which to propose policy solutions. Nonetheless, hosting capacity is a component of locational value, so the latter should mature rapidly. We offer the following policy options:

Option 1: Transition to screening with an initial capacity penetration measure supplemented with key DER impact screening metrics.

Interconnection screening usually consists of simple capacity penetration measures that are generally conservative. These simple and potentially inaccurate capacity penetration measures can be exacerbated by inaccurate load values. Longer-term, screening should employ more sophisticated approaches such as determining hosting capacities for each of multiple negative DER impacts such as over-voltage deviations. These improvements in interconnection screening should be implemented prior to anticipated increases in interconnection request numbers.

Option 2: Consider making hosting capacity data publicly-available.

Regulators may consider requiring that utilities make hosting capacity data publicly available. This would enable developers to deploy DERs at appropriate locations in distribution systems, thereby avoiding costly supplementary studies for interconnection requests. Interconnection of more DERs would therefore be facilitated.

Option 3: Use hosting capacity analysis to guide DER deployment because DERs can be located on feeders or feeder line sections with available hosting capacity.

In addition, distribution system infrastructure upgrading projects on feeders may be deferred by instead deploying DERs on those feeders if a net benefit (from benefit-cost analysis) is derived. Thus, a combination of hosting capacity and infrastructure cost avoidance value may, ideally, be used to guide DER deployment.

Option 4: Consider incentives to defer or even avoid distribution infrastructure investment by instead deploying DERs, if a net benefit is present.

Such incenting of DER deployment will, however, require consistent methodology for determining DER locational value.

Section 5. Integration of Renewable Variable Energy Resources

Background

Variable energy resources, particularly wind and solar energy, are becoming an increasing and significant source of clean electric generation in the Western Interconnection. Western states have been a key driver behind the growth of renewables through renewable portfolio standard policies. Future economic drivers and public policies may increase the level of renewable generation in the electric sector. An important threshold technical question is whether the power system has sufficient flexibility to reliably integrate higher penetration levels of variable energy resources.

A growing body of research is providing new insights on the challenges of integrating high levels of variable renewable generation on the grid. Collectively, this research provides promising steps to improve power system flexibility to integrate higher levels of renewable energy.
This section summarizes the findings of the technical brief titled *Integration of Renewable Variable Energy Resources*.

Key Findings

Improved regional coordination provides greater power system flexibility. Higher levels of renewable energy may be incorporated into the power system if the 38 balancing authorities (BAs) and regions within the Western Interconnection can more easily export surplus generation or import cheaper power to and from other jurisdictions, rather than each operating as a separate island. Fluctuations in renewable energy can be integrated more easily in larger systems with higher load levels.

Diversification of the renewable generation fleet improves power system flexibility with different renewable technologies and the geographic locations of generators. Technological diversity within the renewable generation fleet helps smooth out daily and seasonal variations that can occur among sources of wind, solar, geothermal, and biomass generation. Geographic diversity also helps spread out variation in renewable generation resulting from changing weather conditions, solar intensity, and daylight hours.

Energy storage provides additional power system flexibility. Energy storage allows system operators to separate the time of generation from the time of dispatch. Current storage resource technologies include traditional pump storage, battery storage, and compressed air energy storage systems.

Advanced demand response resources contribute to the ability of the power system to ramp up and ramp down. A future large fleet of electric vehicles could augment the size of demand response resources if strategically coordinated with the power grid.

Improving flexibility of the thermal fleet contributes the ability of the power system to integrate variable generation. Key factors influencing the flexibility of the thermal fleet are minimal down times between shut down and start up, minimum stable generation level, and ramp rates up and ramp rates down.

Options for Moving Forward

Given the challenges surrounding the integration of high levels of variable renewable generation into the grid, policy makers could consider the following options:

Option 1: Identify opportunities to improve power system flexibility.

Public utility commissions could request that utilities within their jurisdiction perform flexibility assessments in their integrated resource planning process to identify options to make the power system more flexible, while meeting foreseeable higher levels of renewable generation.

State energy offices and public utility commissions within a region could propose and sponsor regional level flexibility assessments that would identify foreseeable future renewable generation levels and identify options to improve power system flexibility through better coordination among Balancing Authorities, resource procurement, transmission expansion, and market enhancements.

Option 2: Engage in regional coordination of a larger energy market.

Public utility commissions could ask utilities within their jurisdiction to perform a benefit cost assessment study of participating in the Energy Imbalance Market (EIM).

State energy offices and public utility commissions could support the development and formation of larger and more efficient energy markets that include real time markets, day-ahead markets, and an independent system operator. Potential options to improve markets include the expansion of the California ISO or potentially the new Mountain West Transmission Group.

Public utility commissions could encourage utilities within their jurisdiction to investigate operational technology improvements that enhance the ability of potential buyers and sellers to trade power over the grid.

Option 3: Promote diversification of the renewable mix.

Public utility commissions could ask utilities within their jurisdiction to use their integrated resource planning processes to investigate the benefits of renewable resource diversity. Different renewable technologies and regionally diverse resources can reduce daily or seasonal imbalances.

State energy offices could collaborate to promote and enhance energy trading between high quality wind region and high quality solar regions.

Option 4: Evaluate and implement promising storage technologies.

Public utility commissions could encourage utilities within their jurisdiction to use their integrated resource planning processes to consider whether energy storage would reduce daily or seasonal imbalances in an efficient manner.

State energy offices could establish pilot programs that provide utilities with incentives for implementing promising storage technologies.

Option 5: Evaluate and provide incentives for advanced demand response.

Public utility commissions could encourage utilities within their jurisdiction to use their integrated resource planning processes to investigate the potential for demand response resources in their respective area and to evaluate the potential contributions of Demand Response (DR) resources to enhancing system flexibility.

State energy offices could establish pilot programs that link utilities to recharging systems for EVs and investigate incentives to better align recharging practices with demand response programs.

Option 6: Improve flexibility of the thermal generation fleet

Public utility commissions could encourage utilities within their jurisdiction to use their integrated resource planning processes to evaluate whether utilities in their jurisdiction could improve thermal fleet flexibility through:

- Modifying the existing gas units to improve ramp rates, minimum down times between starts, and minimum operating stable levels.
- Adding new more flexible gas units when additional capacity is needed
- Modifying the existing coal units to improve ramp rates, minimum down times between starts, and minimum operating stable levels.

Section 6. Coal Plant Retirement & Reliability – Frequency Response: Maintaining Reliability with a Changing Resource Mix

Background

The Western Interconnection is experiencing a rapid change of its resource mix, driven by a variety of factors including: a rapid decline in the cost of renewable resources like wind and solar photovoltaics (“PV”), a decline and stabilization of natural gas prices, state and federal political mandates and environmental regulations, and changing customer preferences. The West has seen a number of announced coal plant retirements. Based on the 2012 baseline of Electric Generation Units (“EGU”) from the United States Environmental Protection Agency’s Clean Power Plan, 39% (40 units) of the EGU coal fleet will be retired by 2026, representing 31% (11,331 MWs) of the EGU coal fleet generation capacity in the Western Interconnection. With the retirement of large coal-fired generation units in the West, the question is: can the system still be run safely and reliably? And one measure of reliability is system frequency response.

Frequency is the number of cycles or oscillations of alternating current in a power system, and frequency response is a measure of an Interconnection’s ability to arrest frequency changes and stabilize frequency immediately following the sudden loss of generation or load. Key features of the system play crucial roles in the frequency response of the grid including inertial response, primary frequency response, and secondary frequency response:

1. Inertial response is generally the first system feature to contribute to frequency response and it occurs in the arresting period immediately after an event. Inertial response is provided by the large rotating mass of a generator or in load (i.e. an inductive motor) that can help balance supply with demand by absorbing or releasing kinetic energy from the rotating mass into the system.
2. Primary frequency response, which occurs during the rebound period following the arresting period, is provided by an autonomous generator governor that changes the power output of the generator to stabilize frequency.
3. Secondary frequency response occurs during the recovery period and is provided by the redispatch of generation to change the power output of generation resources in the minutes following an event to bring frequency back to normal.

Frequency response is extremely important to the reliable operation of the grid. With the transformation of the resource mix from resources like large centralized coal-fired generators that are synchronized with the system frequency, to more asynchronous generation like wind and distributed solar, some of the frequency response services inherently provided by large, synchronous generation resources—that system operators take for granted today—may not be available to the same extent in the future.

This section summarizes the findings of the technical brief titled *Coal Plant Retirement & Reliability – Frequency Response: Maintaining Reliability with a Changing Resource Mix*.

Key Findings

Inertial response is the first line of defense and helps curb the initial decline of frequency immediately following a system disturbance. Generators with a large spinning mass synchronized with the frequency of the grid provide inertial response.

> **Synthetic inertia can be provided by properly designed wind plants**. Wind plants are not synchronized with the grid frequency the same way as synchronous generators because they are connected to the grid through power electronics that can allow the wind plant to provide synthetic inertia if set up properly.
>
> **Frequency-ride through of small generators is important** so that a simultaneous tripping of a large number of small generators, like roof-top solar resources, does not adversely affect the frequency response of the system.

Primary frequency response works to stabilize frequency immediately following the initial frequency deviation. It is typically provided by generator governors or other control equipment, which allow the power output to stabilize frequency.

> **The amount of primary frequency response has been on the decline** for the past couple decades, even before there was significant change in the resource mix toward non-synchronous generation. Governor withdrawal from conventional synchronous generators has been a serious problem and a main contribution to the decline in primary frequency response. Using a standard control response helps improve the governor withdrawal problem because it provides a coordinated and sustained primary frequency response.
>
> **Faster frequency response can provide more value to the system** because it can curb the frequency decline and require less capacity because the response is more accurate. Asynchronous resources that are inverter-based like wind, solar, battery storage, etc. can provide faster responses than traditional thermal generators.
>
> **Monitoring primary frequency response is critical** because not all generators need to be providing primary frequency response all the time.

Secondary frequency response is the redispatch of contingency reserves to restore frequency back to normal operation.

> **Frequency response is a responsibility of all entities** in the synchronized interconnection and even entities not responsible for a disturbance event are expected to help restore frequency back to normal as quickly as possible.

Options for Moving Forward

Given the uncertainty of future frequency response needs, the following options are offered now for Western states and provinces to consider:

Option 1: Ensure that all new generation resources have the ability to provide primary frequency response and synthetic inertia.

Before a generator can respond to a deviation in system frequency, it must have the ability to respond. The ability to provide primary frequency response and synthetic inertia requires the installation of the necessary control equipment.

The following areas are places where states can look to implement this option:

- *Public Utility Regulatory Policies Act ("PURPA") qualifying facility small generator interconnection standards*
- *Renewable Portfolio Standard ("RPS") rules and regulations*
- *Investor-owned utility's ("IOUs") integrated resources plans ("IRP")*
- *Net-metering rules and regulations*

Option 2: Monitor system frequency response and system inertia at the utility (Balancing Authority) level to ensure that primary frequency response is provided in a predictable fashion.

By monitoring and measuring frequency response, states can determine whether utilities within each state are providing proper frequency response and whether further local action is required.

The following areas are places where states can look to implement this option:

- *Investor-owned utility's ("IOUs") integrated resources plans ("IRP")*

Option 3: Ensure that IOUs and organized markets recognize the value of a fast and accurate response to frequency deviations.

Faster and more accurate frequency response is more valuable to the system than a slower and more cumbersome response. A fast frequency response can help return the system to normal more quickly and reduces the possibility of under-frequency load shedding or over-frequency generation tripping due to spikes in frequency. A fast frequency response can also achieve the same result as a slower frequency response, but using fewer megawatts of capacity.

The following areas are places where states can look to implement this option:

- *Federal Energy Regulatory Commission ("FERC") rulemakings*
- *Organized wholesale energy and ancillary service markets*
- *Investor-owned utility's ("IOUs") integrated resources plans ("IRP")*